<u>ELECTRICITY– Q&A</u>

What is the CPUC's forecast for electric rates for the next several years?

In setting electric rates, the CPUC establishes an electric revenue requirement for a future "test year" based on the utility's cost of service. This includes the utility's cost of owning and operating its transmission, distribution, generation facilities, its fuel and purchased power expenses including the cost of paying the California Department of Water Resources (DWR) revenue requirements, and its cost for implementing public purpose programs such as energy efficiency programs, low-income discounts and energy efficiency assistance, renewable programs, and research and development programs. Rates are set on a short term, annual forecast basis. The CPUC does not forecast electric rates for longer term periods.

The rates for Southern California Edison may increase slightly, e.g., by approximately 1%, in the 1st quarter of 2006, as a result of its pending general rate case. PG&E's rates may increase by an additional 3% in 2006 due to FERC authorized transmission rate increases, the California Solar Initiative, and authorization for demand response program funding.

What factors will cause rates to change?

Gas prices are a key element affecting electric rates. Gas prices affect the utility's fuel and purchased power expenses including the revenue requirement to pay for the DWR contracts. The cost of maintaining the utility's transmission, distribution, and generation facilities to ensure safe and reliable service affect the utility's revenue requirements and rates. The utility's cost of capital and authorized rate of return are affected by financial conditions including interest rates, and these factors impact electricity rates. Programs to enhance reliability and the environment such as demand response programs and the Solar Initiative affect rates.

What are the relative proportions of generation, transmission and distribution in system electric rates for each major investor-owned utility?

These relative proportions of generation, transmission, and distribution revenues in current electric rates are shown below:

<u>Edison</u>

Generation: 60%
Distribution: 23%
Transmission: 3%
Other (public purpose, nuclear decommissioning, on-going CTC, fixed transition amount): 14%

SDG&E

Generation: 43%
Distribution: 31%
Transmission: 14%
Other: 15%

PG&E

Generation: 53%
Distribution: 27%
Transmission 7%
Other: 13%

Does the CPUC intend to reduce rates? How will this be accomplished?

In various ratemaking proceedings, the CPUC endeavors to make sure that the utilities' requests for cost recovery are reasonable and that the utilities do their best to keep costs at a minimum consistent with the mandate to ensure reliable service and to meet the energy policy goals set by the Energy Action Plan. All of the utilities' requests for cost recovery and rate increases are examined in formal proceedings following a rigorous public process that provides for fact finding and public participation. Rates are reduced when costs decline and vice versa. Rates for PG&E customers were reduced by $800 million following the bankruptcy settlement (D.04-02-062). Similarly, the Commission reduced rates for Southern California Edison's customers by $1.25 billion in D.03-07-029 after the Procurement Related Obligations Account (PROACT) was paid off.

The CPUC will reduce rates if it determines that the utilities' costs of serving customers will decline. The CPUC reviews non-fuel related costs of service in the utilities' general rate cases and fuel related expenses in the annual Energy Resource Recovery Account proceedings. If the CPUC determines in these proceedings that costs are lower than what the utilities are currently recovering in rates, it will require that the utilities lower rates to reflect the reduction in costs.

What are the current cost responsibility surcharge under-collections for each IOU? What are the forecasted under-collections and projected repayment dates?

Current Under-Collections

In the Feb 1, 2006 Final Report of the Cost Responsibility Surcharge (CRS) Calculation working group established by ALJ Pulsifer, the parties (PG&E, SCE, AreM, CLECA, CMTA, TURN, and DRA) jointly recommended adoption of the following under-collection estimates, as of the end of 2005:

PG&E under-collection: $60 million

Edison under-collection: $577 million

SDG&E under-collection: None. The under-collection has been paid off in SDG&E territory, as of approximately November 2005.

Forecast Under-Collections and Projected Repayment

PG&E: working group members developed estimates showing that the current $60 million under-collection in PG&E territory will be repaid about midway through 2006.

Edison: working group members developed estimates showing that the current $577 million under-collection in Edison territory will be repaid sometime in 2008.

NATURAL GAS – Q&A

Please list the CPUC decisions between 2000 and the present, and describe the policies set made regarding:

- **Procurement of natural gas for core customers by local distribution companies (LDCs), including specifically any assessments of the merits of long versus short positions for procurement of gas supply for end-use customers**

In the mid-1990s, the Commission established gas cost incentive mechanisms for California's three largest natural gas utilities, SDG&E, SoCalGas, and PG&E. An incentive mechanism for Southwest Gas became effective in 2005. These mechanisms eliminate "reasonableness reviews" of natural gas procurement costs for these utilities, and provide a financial incentive for the utilities to procure natural gas at prices below monthly market prices. If the utilities procure natural gas at costs below annual benchmark costs, which are based on monthly market indices, the utility receives a financial reward. If the utilities procure natural gas at costs above the annual benchmark costs, the utility incurs a financial penalty. These performance based incentives allow the utilities considerable flexibility to procure natural gas for core customers and manage natural gas costs.

The mechanisms provide the utilities with general authority to purchase natural gas financial instruments to hedge the price of natural gas, since the costs and gains due to the use of financial instruments are typically included as actual costs in the gas cost incentive mechanisms. While the Commission reviews the operation and performance results of the gas cost incentive mechanisms on an annual basis, and staff often discusses procurement activities with the utilities, the CPUC does not micromanage utility procurement activities, including the use of financial instruments.

The Commission has not addressed in any decision between 2000 and the present the general merits of long versus short positions for natural gas procurement for end-use customers. In Decision (D.) 05-10-015 and D.05-10-043, discussed below, the Commission approved confidential hedge plans for PG&E and SoCalGas/SDG&E, respectively, in order to protect utility gas customers from potentially very high gas prices, and removed the costs and potential gains associated with those hedging activities from the gas cost incentive mechanisms of those utilities.

Given the recent tightening of the gas supply market and the increased volatility in gas prices, the Commission may consider modifying existing incentive mechanisms to encourage (or require) the utilities to manage gas risk similar to the way they manage electric risk, i.e. with a combination of long, medium, and short-term transactions, including financial hedging products. In considering these changes, the Commission will address the utilities' recent claims, following the escalation in gas prices after Hurricane Katrina, that the current incentive mechanisms, by basing rewards and penalties on a monthly index, disincent hedging and longer term transactions.

With regard to natural gas procurement in general for core customers by LDCs, the Commission issued the following decisions:

a. D.00-06-039: Awarded SoCalGas $7.7 million for savings under its Gas Cost Incentive Mechanism (GCIM) Year 5, ordered staff to file an evaluation report on the GCIM, and extended the term of the GCIM.

b. D.01-05-002: Awarded SoCalGas $9.8 million for savings under its GCIM Year 6.

c. D.01-05-003: Corrected a flaw in the method of calculating the procurement rate for SDG&E core and noncore customers, and ordered a rebate to core customers.

d. D.02-06-023: Adopted modifications to SoCalGas' GCIM, and ordered the Commission's Energy Division to prepare an Order Instituting Investigation to determine whether utilities caused 2000/2001 gas price spikes.

e. D.02-08-064: Found Southwest Gas' procurement practices in 2000-2001 to be unreasonable, and ordered Southwest Gas to refund $2.7 million.

f. D.02-08-065: Declined to adopt a SoCalGas/SDG&E proposal to consolidate their core procurement departments, and adopted rules for eligibility for core service for noncore customers.

g. D.03-07-037: Modified and extended the term of the SDG&E gas procurement PBR.

h. D.03-08-064: Awarded SoCalGas $17.4 million for performance under Year 8 of the GCIM, pursuant to the modified GCIM adopted in D.02-06-023.

i. D.03-08-065: Awarded SoCalGas $30.8 million for performance under Year 7 of the GCIM, pursuant to the modified GCIM adopted in D.02-06-023.

j. D.03-12-061: This decision primarily addressed PG&E's backbone transmission and storage rates, but it also extended the term of the PG&E Core Procurement Incentive Mechanism (CPIM).

k. D.04-02-060: Adopted a GCIM reward for SoCalGas under Year 9 of the GCIM of $6.3 million, subject to the outcome of I.02-11-040.

l. D.04-09-022: This "Phase 1" decision of the Commission's Gas Supply and Infrastructure Rulemaking proceeding included several key policies: Adopted procedures under which natural gas utilities enter into contracts for firm interstate pipeline capacity rights for their core customers, and allowed the utilities to decrease the amount of pipeline capacity SoCalGas held at the time for noncore customers.

m. D.05-04-003: Adopted a GCIM reward for SoCalGas under Year 10 of the GCIM for $2.3 million, subject to the outcome of I.02-11-040.

n. D.05-05-033: Adopted a gas cost incentive mechanism for Southwest Gas.

o. D.05-10-015: Authorized PG&E to purchase financial hedge contracts in order to protect core customers from the possibility of very high prices in the winters of 2005-2006, 2006-2007, and 2007-2008. The Commission also removed these costs from treatment under the CPIM, thereby protecting the utility from risk that the contracts would result in higher costs. The hedging plan was submitted confidentially to the Commission.

p. D.05-10-043: Authorized SoCalGas and SDG&E to purchase financial hedge contracts in order to protect core customers from the possibility of very high prices in the winter of 2005-2006. The Commission also removed these costs from treatment under the GCIM, thereby protecting the utility from risk that the contracts would result in higher costs. The hedging plan was submitted confidentially to the Commission.

q. D.05-11-004: Allowed SoCalGas and SDG&E to file an application to consolidate their core procurement portfolios.

r. D.05-11-027: Authorized SoCalGas to convert 4 billion cubic feet of very low cost "cushion gas" in storage to "working gas" and sell that gas to low-income customers in the winter of 2005-2006.

- **Holding/release of firm interstate pipeline capacity by LDCs**

  a. D.02-07-037: Established rules for California subscription to "turned-back" El Paso interstate pipeline capacity, and required natural gas and large electric utilities to sign up for a portion of the El Paso capacity.

  b. D.04-01-047: Established cost allocation methodology for costs of the "El Paso turned back capacity" obtained by utilities pursuant to D.02-07-037.

  c. D.04-09-022: This "Phase 1" decision of the Commission's Gas Supply and Infrastructure Rulemaking proceeding includes several key policies: Adopted procedures under which natural gas utilities enter into contracts for firm interstate pipeline capacity rights for their core customers, and allowed the utilities to decrease the amount of pipeline capacity SoCalGas held at the time for noncore customers.

- **Expansion of utility system transport capacity at the interconnections between the SoCal system and the Kern River pipeline; between the PG&E system and the Kern River pipeline; between the PG&E and SoCal systems; at the entry points to the SoCal system on the Arizona border (Ehrenberg and Topock)**

  a. D.01-12-018: Approved the Comprehensive Settlement Agreement (CSA) for SoCalGas and SDG&E, which adopted a system of firm tradable capacity rights at SoCalGas transmission receipt points, and found that this system would provide economic signals related to the construction of new intrastate transmission facilities. (*Note:* The Commission never implemented the CSA framework. Due to controversy over the implementation advice letters, the Commission ordered SoCalGas to file an application to implement the CSA framework. SoCalGas filed an application, which the Commission adopted in D.04-04-015, but the decision was stayed.)

  b. D.04-04-015: Adopted implementation of D.01-12-018, but stayed its order pending the issuance of a decision regarding firm tradable rights in the Commission's Gas Supply and Infrastructure Rulemaking.

  c. D.04-09-022: As noted above, this is the Phase 1 decision of the Gas OIR. With regard to receipt point issues, the decision:
     - adopted a nomination system for SoCalGas that would allow increased deliveries through Kramer Junction, the Kern River interconnect with SoCalGas;
     - allowed SoCalGas and SDG&E to establish new receipt points as needed at Otay Mesa, Salt Works Station and Center Road Station, with Otay Mesa being a "common receipt point" for both utilities;
     - required SoCalGas and SDG&E to request a system of firm tradable rights in another application;
     - adopted policy on the cost responsibility for new utility infrastructure required to bring in new supplies, and;

– required the natural gas utilities to file nondiscriminatory open access tariffs for interconnections with new supply sources.

Please list the decisions of the CPUC between 2000 and the present, and describe the policies set forth in those decisions, regarding the formulas for reflecting the price and cost of natural gas in electric rates.

Natural gas prices affect electric rates through the IOUs' Energy Resource Recovery Accounts (ERRA). These accounts were established pursuant to D.02-10-062. D.02-12-074 modified and clarified D.02-10-062. The electric utilities file annual applications for Commission approval of forecast and actual expenditures in the ERRA account to recover energy procurement costs associated with fuel and purchased power, utility retained generation, ISO related costs and costs associated with its residual net short procurement requirements to serve its bundled service customers. Also included are costs for: qualifying facility (QF) contracts, inter-utility contracts, irrigation district contracts and other Power Purchase Agreements (PPA), bilateral contracts, forward hedges, pre-payments and collateral requirements associated with procurement (including disposition of surplus power), and ancillary services.

The dollars accrued in each IOU ERRA is passed through to rate payers through the revenue requirement for that IOU. The ERRA excludes DWR power purchase contract costs. The specific treatment of natural gas costs for QF power, DWR power purchase contracts, and utility retained generation and bilateral contracts are described below.

QF Power: In D.96-12-028, the Commission adopted the "Transition Formula," pursuant to Section 390 of the California Public Utilities Code (Section 390), in order to calculate monthly short run avoided cost (SRAC) as-available energy prices paid to QFs. Section 390 was part of the legislation for restructuring the electric industry in California under Assembly Bill (AB) 1890. Section 390 prescribes the basic elements for determining as-available energy prices paid to QFs based on "an average of current California natural gas border price indices," pursuant to Section 390(b).

Modifications to the Transition Formula have been considered in *Order Instituting Rulemaking into Implementation of Pub. Util. Code Section 390*, R.99-11-022. To date, sixteen decisions have been issued in R.99-11-022. These decisions can be grouped as follows:

- **Transition Formula Pricing – 6 Decisions.** D.00-10-030 denied a June 28, 2000 emergency motion by Edison to implement a provisional QF avoided cost posting for September 2000 and future months, which would have reduced SRAC energy payments. D.01-03-067 revises Edison's transition formula 'factor' adopted in D.96-12-028 and establishes a procedure to replace the Topock index adopted in D.96-12-028, which have the effect of reducing SRAC energy payments to QFs under contract to Edison. The Commission issued three decisions (D.01-12-025, D.02-02-028, and D.02-04-065) to address requests for rehearing and/or petition for modifications. D.05-09-003 is a relatively minor decision that relieved "the IOUs of the obligation to pay QFs, that have power purchase agreements (PPA) with the IOUs, within 15 days of the end of the QF billing period."

- **Contract Amendments -- 7 Decisions**. D.01-06-015 "pre-approved three voluntary QF contract amendments for Edison, SDG&E, and PG&E that address the special circumstances presented by the dysfunctional wholesale market in California." The three contract amendments were: (1) a 5-year, fixed-price energy payment of 5.37 cents/kWh, (2) supplemental energy payments, or (3) incentive payments for excess QF generation. There are six additional decisions on issues related to these contract amendments: D.01-07-031, D.01-09-021, D.01-09-027, D.01-10-069, D.02-01-033, and D.02-05-012. These decisions did not specify any changes to the SRAC energy pricing transition formula.

- **Line Loss Factors – 2 Decisions**. D.01-01-007 revised the line loss factors used to calculate energy deliveries. D.01-06-043 denied a request for rehearing on certain issues.

- **QF Switchers – 1 Decision.** Directed PG&E to pay QFs, which exercised their one-time option to switch to Power Exchange (PX) pricing, SRAC payments based on the Transition Formula adopted in D.96-12-028, or as modified, for power produced as of January 19, 2001.

DWR Power Purchase contracts: Under the Rate Agreement between the CPUC and DWR, the CPUC is obligated to accept DWR's annual revenue requirement forecast and ensure that it is collected from IOU ratepayers and remitted to DWR. The CPUC cannot change a request from DWR, and has no say regarding how DWR estimates its annual contract costs, including the forecast price of natural gas used by DWR in its estimates.

Regarding the overall influence of the cost of natural gas on DWR's annual contract costs: first, many of DWR's contracts are based on fixed contract prices, so their cost does not change when the price of natural gas changes. A second group of DWR's contracts are dispatchable at the discretion of the IOU that has been assigned that contract. Those contract costs do change with the price of natural gas (DWR purchases gas for these contracts pursuant to IOU recommendations). Finally, two of DWR's base and peak load contracts include a "gas tolling" provision, under which DWR (on behalf of the IOU to which the contract is assigned) purchases the gas that supplies the plant that generates the electricity to supply that contract.

Utility retained gas fired generation and bilateral contracts where the utility supplies the gas: D. 02-10-062 established the ERRA account and a semi-annual update process for fuel and purchased power forecasts recorded in the ERRA. The ERRA includes generation fuels. In the first half of the year, the IOU's file an application for annual fuel and purchased power forecasts. In the second half of the year, the ERRA balance account is reviewed for reasonableness and prudence. D.04-01-014 modified the dates for 2004 and 2005.

D.02-12-074 approved the IOU's short term procurement plans and modified/clarified D.02-10-062. D.02-12-074 requires the IOUs to file monthly reports with supporting documents supporting each entry over $100 to the CPUC Energy Division.

The Commission authorized the use of hedging instruments to protect ratepayers from some of the risk of variation in natural gas prices. D.02-08-071, provided utilities the authority to use financially-settled hedging instruments for interim procurement, including natural gas hedges. D. 02-10-062, listed products that the Commission determined were appropriate to meet procurement needs including calls, swaps, gas storage and forward gas purchases. D. 03-12-062, continued authorization of the procurement products listed in D. 02-12-062.

Please describe the CPUC's technical resources, capabilities and programs for monitoring natural gas supply and price movements for purposes of setting gas and electric rates.

The CPUC wishes to first clarify the relation between natural gas supplies and prices and natural gas utility rates.

First, natural gas utilities only procure supplies for core customers. Although core customers are by far the most numerous, their delivered volume only constitutes about a third of the utilities' delivered supplies. Other customers procure their own supplies.

Second, the utilities' procurement cost of natural gas is recovered in a "procurement rate" that is part of the core customers' natural gas rate. (The other major component of customers' rates is the transportation rate, which recovers the utilities' operation and capital costs.) Procurement costs are generally based on wholesale natural gas transactions trading in a national market. The procurement rate is changed every month by each of the four major natural gas utilities in California, in order to reflect the utilities' expectation about the procurement costs it will incur during the upcoming month. Actual costs are ultimately recovered through a "balancing account" which is amortized, also as part of the procurement rate.

Third, the utilities propose to the Commission every month what the new procurement rate should be, through a regulatory vehicle called "advice letters" (ALs). These advice letters are typically very routine filings. The staff of the CPUC's Energy Division has the authority to approve these ALs, which it typically does on a routine basis. The CPUC's Division of Ratepayer Advocates also reviews these filings, acting as an advocate for core customers, and may protest the filings if it believes the rates are calculated incorrectly or improperly.

For reviewing the utility filings to assure that natural gas rates are close to market prices, we have capable staff and access to important pieces of industry information. Staff in the Energy Division's natural gas section have experience in natural gas regulation that ranges from a few years to 15 years. The CPUC's Division of Ratepayer Advocates also has staff with a similar level of natural gas regulatory experience.

CPUC staff has access to key pieces of market information about natural gas prices and natural gas industry developments. For example, we subscribe to:

- *Gas Daily* and *Natural Gas Intelligence* which provide well-accepted industry price indices and current information about daily, weekly, and monthly prices, NYMEX prices and natural gas industry and regulatory developments,
- *Foster Natural Gas Report*
- PIRA consulting services

Staff in the Energy Division, the Division of Ratepayer Advocates, and the Division of Strategic Planning reviews these publications rigorously.

The Energy Division and DRA hold regular discussions with natural gas utilities, including biweekly phone calls with SoCalGas to discuss market developments and prices.

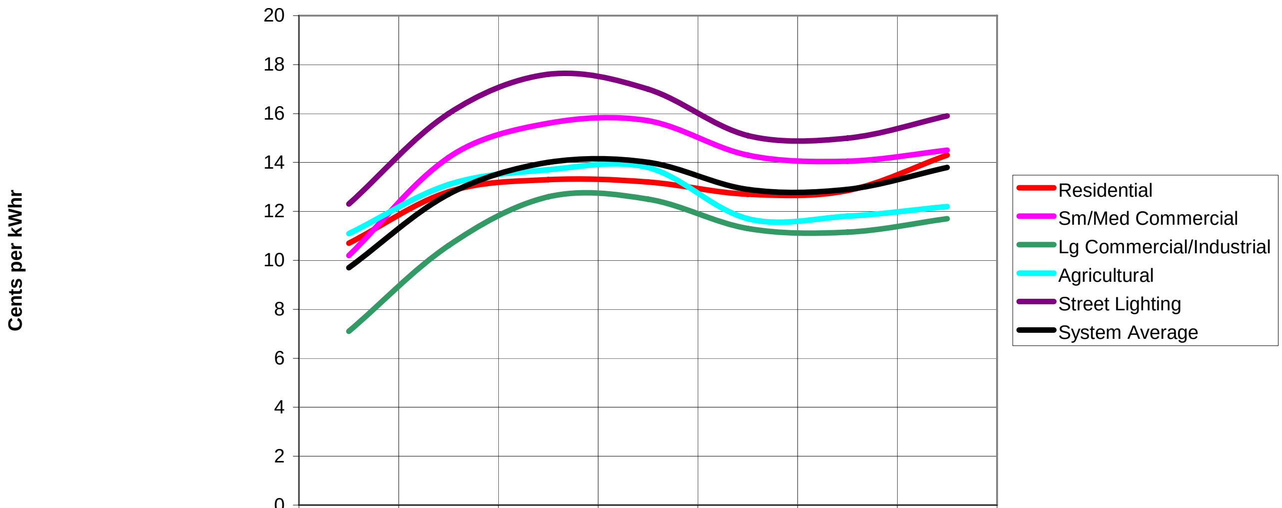
CPUC staff and staff from other state government agencies such as the California Energy Commission have been meeting on a monthly basis for several years to discuss natural gas issues, including prices.

Finally, we also occasionally have meetings with industry representatives to discuss natural gas supply and price issues.

While we have good understanding of financial instruments and their use as price hedging and speculative tools, staff has limited *detailed* expertise on natural gas financial instruments, and limited time to analyze short-term price movements in relation to events in the financial market. Improvement in this area would better our ability to analyze natural gas prices, but is not necessary for the purpose of setting monthly natural gas rates.

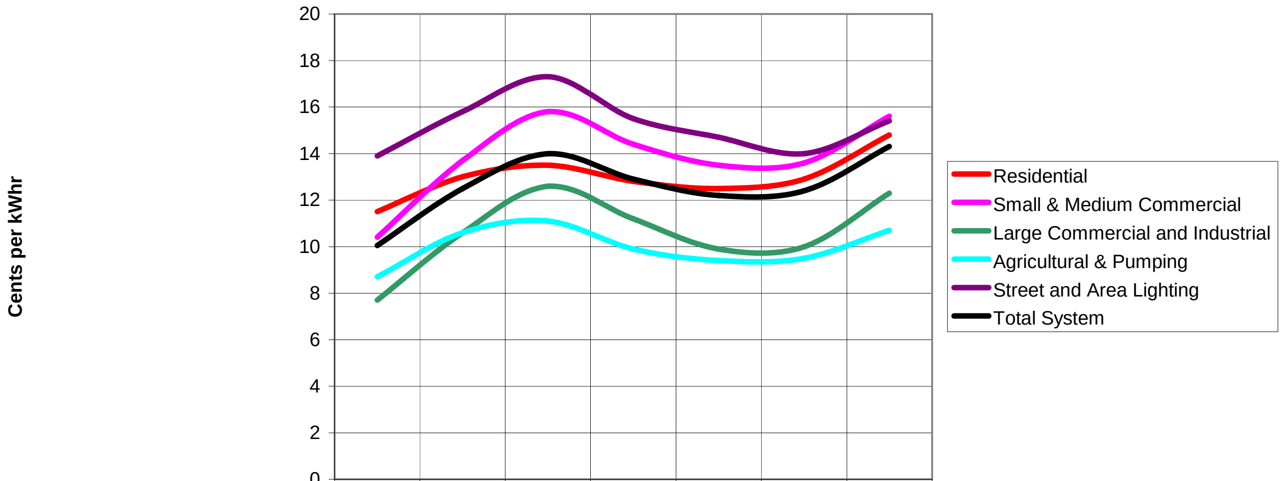
Gas price forecasts are used in setting electric utilities' fuel and purchased power revenue requirements in Commission proceedings. CPUC staff reviews these forecasts in the course of these proceedings.

Attachment 1, Chart 1
Pacific Gas and Electric Company
Annual Avg. Bundled Customer Rates (Cents/kWhr)



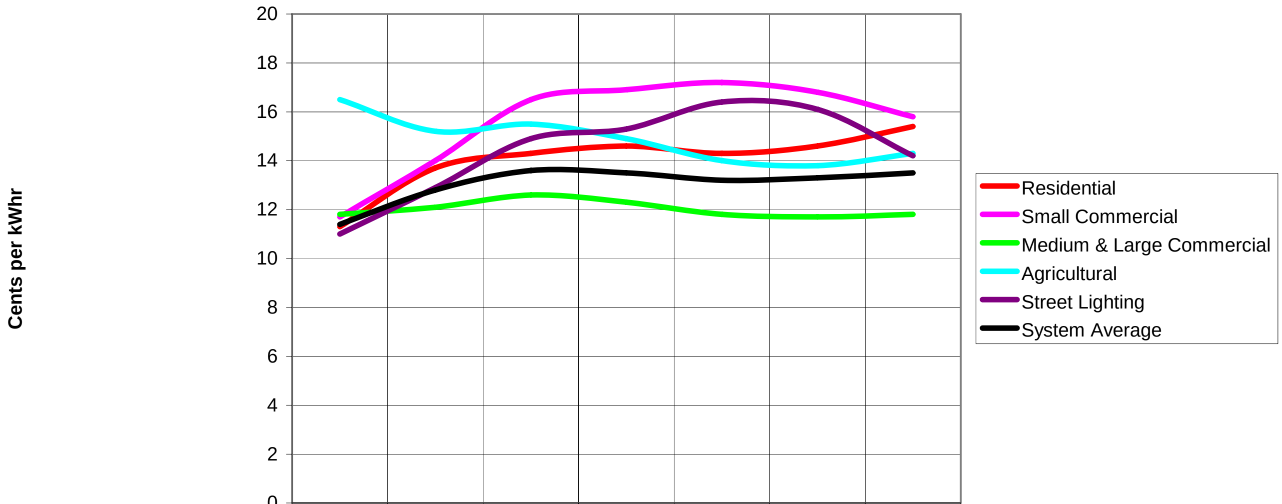
	2000	2001	2002	2003	2004	2005	2006
Residential	10.7	12.8	13.3	13.2	12.7	12.85	14.3
Sm/Med Commercial	10.2	14.2	15.6	15.7	14.3	14.05	14.5
Lg Commercial/Industrial	7.1	10.6	12.6	12.5	11.3	11.15	11.7
Agricultural	11.1	13.1	13.7	13.8	11.7	11.8	12.2
Street Lighting	12.3	16	17.6	17	15.1	15	15.9
System Average	9.7	12.7	14	14	12.9	12.9	13.8

Attachment 1, Chart 2
Southern California Edison Company
Annual Avg. Bundled Customer Rates (Cents/kWhr)



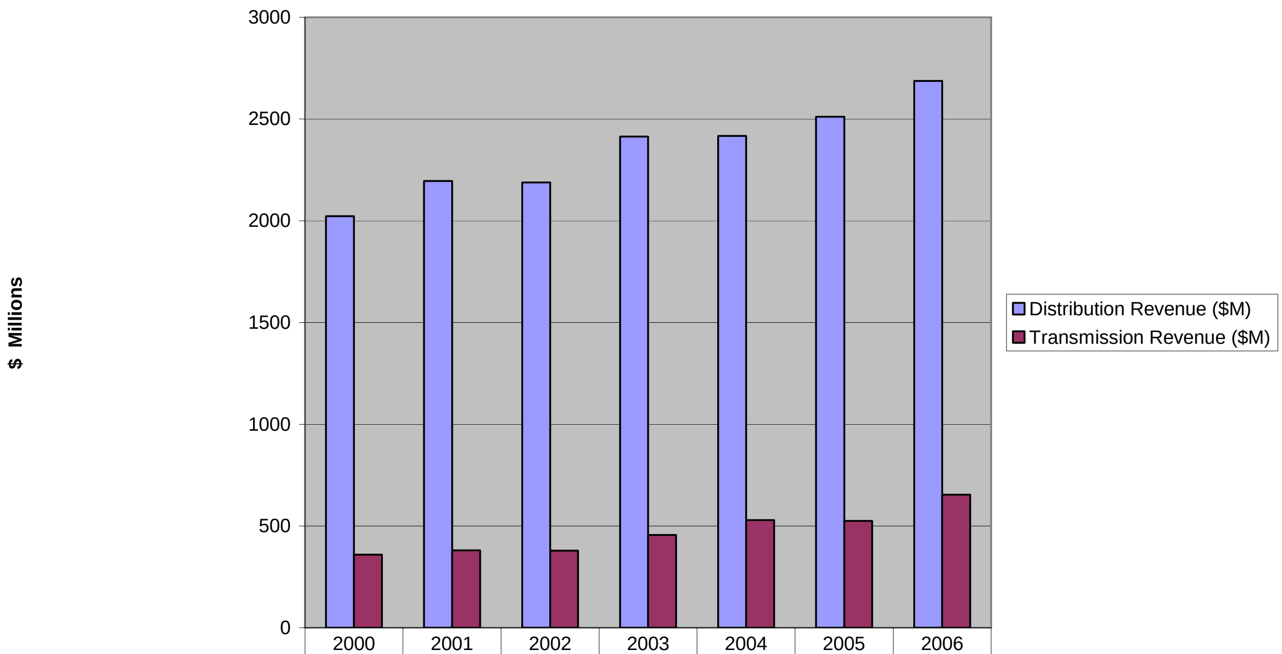
	2000	2001	2002	2003	2004	2005	2006
Residential	11.5	13	13.5	12.8	12.5	12.9	14.8
Small & Medium Commercial	10.4	13.7	15.8	14.4	13.5	13.6	15.6
Large Commercial and Industrial	7.7	10.6	12.6	11.2	9.9	10	12.3
Agricultural & Pumping	8.7	10.6	11.1	9.9	9.4	9.5	10.7
Street and Area Lighting	13.9	15.8	17.3	15.5	14.7	14	15.4
Total System	10.04	12.5	14	12.9	12.2	12.4	14.3

Attachment 1, Chart 3
San Diego Gas & Electric Company
Annual Avg. Bundled Customer Rates (Cents/kWhr)



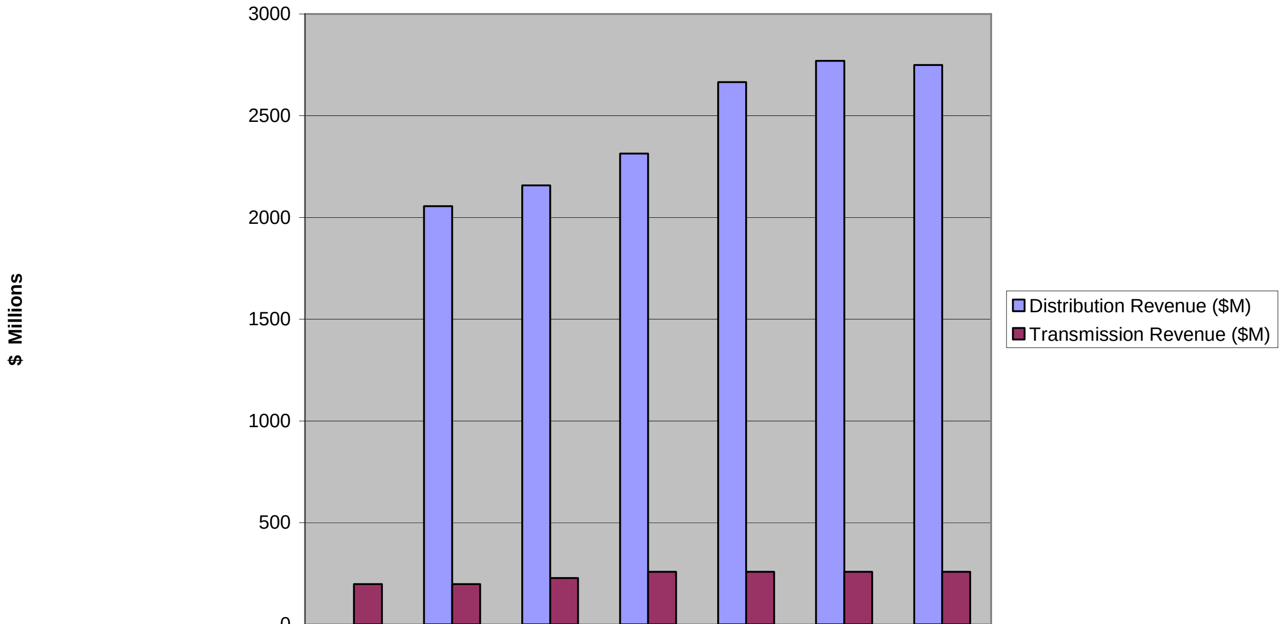
	2000	2001	2002	2003	2004	2005	38749
Residential	11.3	13.7	14.3	14.6	14.3	14.6	15.4
Small Commercial	11.7	14	16.5	16.9	17.2	16.8	15.8
Medium & Large Commercial	11.8	12.1	12.6	12.3	11.8	11.7	11.8
Agricultural	16.5	15.2	15.5	14.9	14	13.8	14.3
Street Lighting	11	12.9	14.9	15.3	16.4	16.1	14.2
System Average	11.4	12.8	13.6	13.5	13.2	13.3	13.5

Attachment 2, Chart 1
Pacific Gas and Electric Company
Annual Revenue Requirements for Distribution and Transmission 2000-2006 ($M)



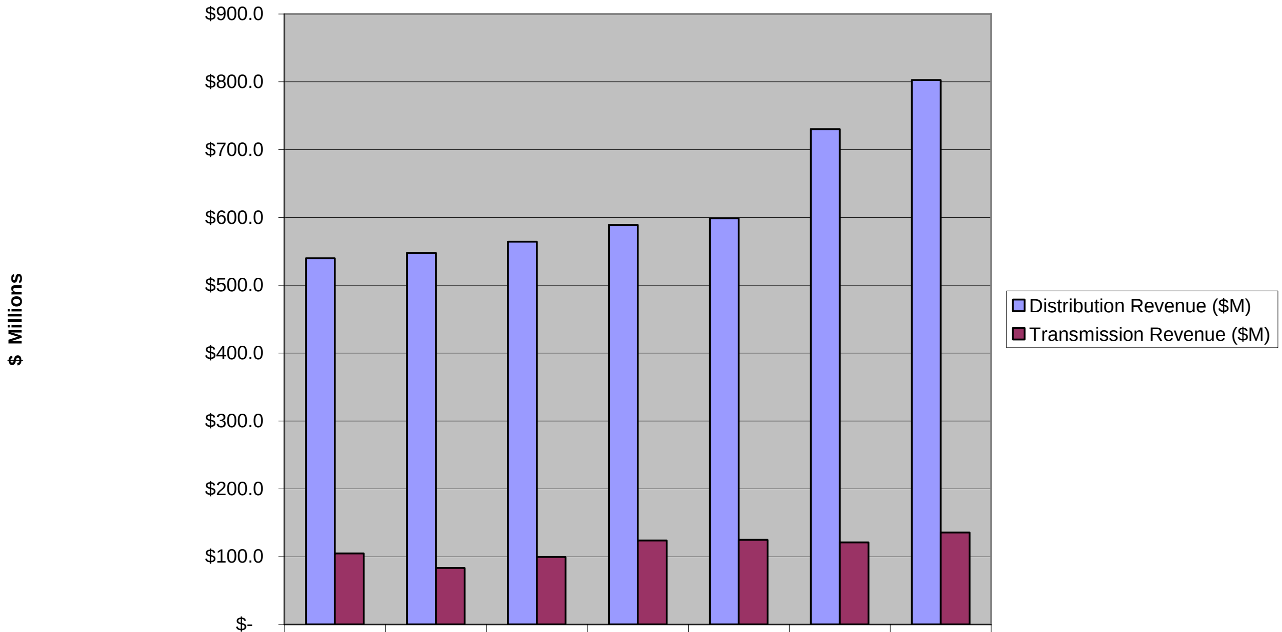
	2000	2001	2002	2003	2004	2005	2006
Distribution Revenue ($M)	2022.3	2194.7	2187.9	2413.8	2417	2511.5	2687.4
Transmission Revenue ($M)	359	380.5	379	455.5	530	524.5	654

Attachment 2, Chart 2
Southern California Edison Company
Annual Revenue Requirements for Distribution and Transmission 2000-2006 ($M)



	2000	2001	2002	2003	2004	2005	2006
Distribution Revenue ($M)	0	2055	2158	2313.5	2665	2770	2750
Transmission Revenue ($M)	198	198	228	258	258	258	258

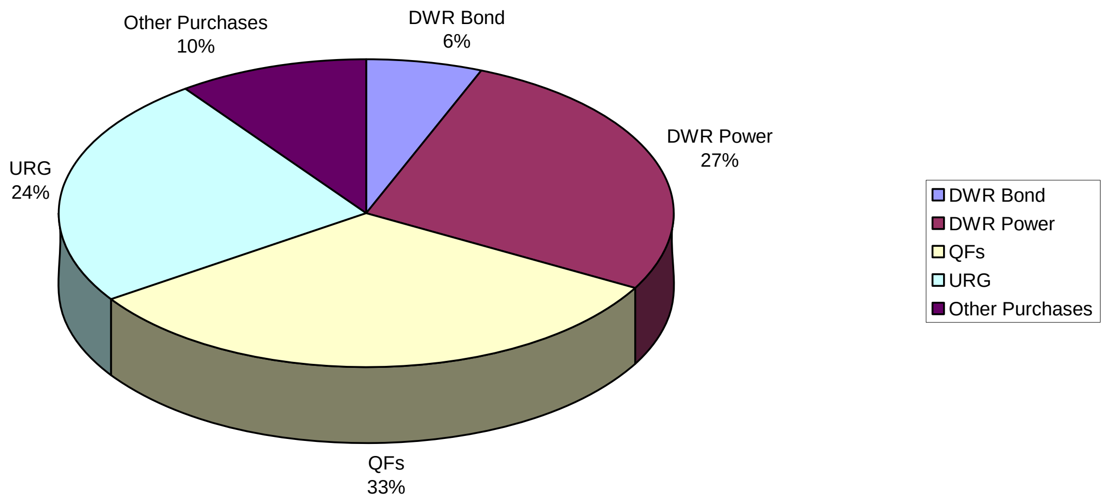
Attachment 2, Chart 3
San Diego Gas & Electric Company
Annual Revenue Requirements for Distribution and Transmission 2000-2006 ($M)



	2000	2001	2002	2003	2004	2005	2006
Distribution Revenue ($M)	539.9	547.8	564.2	589.2	598.7	730.3	802.7
Transmission Revenue ($M)	104.7	83.4	99.8	123.9	124.7	121.1	135.6

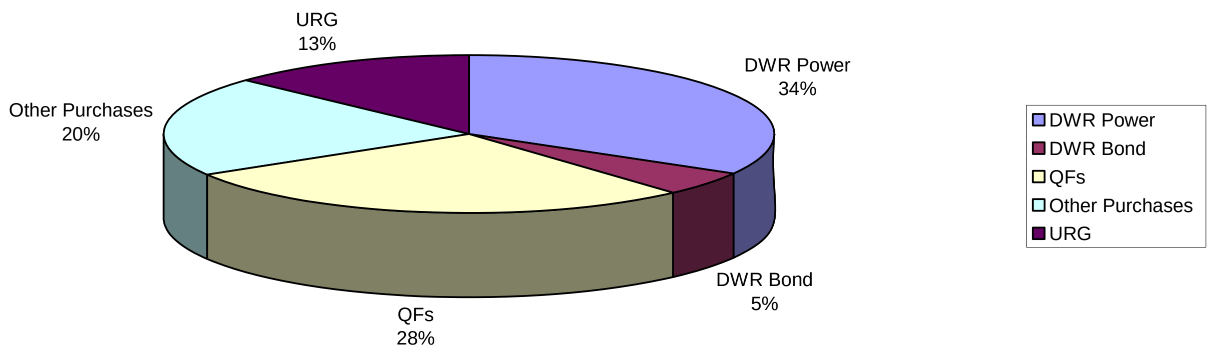
Attachment 3, Chart 1
Pacific Gas and Electric Company

Generation Rate Percentages Effective 2006



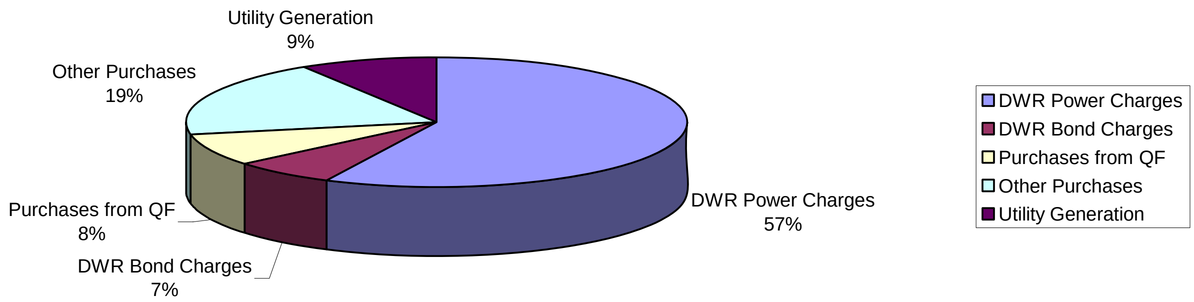
Attachment 3, Chart 2
Southern California Edison Company

Generation Rate Percentages Effective 2006



Attachment 3, Chart 3
San Diego Gas & Electric Company

Generation Rate Percentage Effective 2/1/2006



ATTACHMENT 4, TABLE 1						
SOUTHERN CALIFORNIA GAS COMPANY ANNUAL AVERAGE NATURAL GAS RATES						
CENTS PER THERM						
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Residential						
Transportation Rate	43.01	40.44	43.15	42.60	44.77	44.69
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge *	1.21	1.63	2.93	2.78	3.70	3.80
Total Rate	86.38	86.67	74.69	92.93	103.79	121.89
Core C&I						
Transportation Rate	29.25	25.62	28.46	27.62	29.38	28.90
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge	1.21	2.83	3.52	2.71	3.63	3.44
Total Rate	72.61	73.05	60.59	77.88	88.03	105.74
NonCore C&I						
Transportation Rate	5.75	3.98	4.14	5.04	5.55	6.00
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge *	1.21	1.03	1.72	0.91	1.83	1.83
Total Rate	49.12	49.61	34.46	53.49	62.55	81.23
EG						
Transportation Rate	3.69	2.53	1.97	2.80	3.24	3.75
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge *						
Total Rate	45.85	47.14	30.58	50.35	58.56	77.15
Wholesale Total						
Transportation Rate	2.80	0.01	0.98	1.81	2.24	2.69
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge *						
Total Rate	44.96	44.62	29.59	49.36	57.56	76.09
NGV						
Transportation Rate	11.08	11.26	11.33	11.54	11.66	11.64
Procurement Rate	42.16	44.60	28.61	47.55	55.32	73.40
PPP Surcharge *	1.21	1.02	1.71	0.90	1.82	1.80
Total Rate	54.44	56.89	40.70	59.98	68.64	86.84
Notes:						
* PPP Surcharge started July 2001. For the period Jan 2000 to July 2001, we have noted the CARE surcharge.						
Residential class average rates includes transport and procurement customers, excludes large master meter cus						
Class average rates includes customer charge revenues.						
Procurement rates for noncore C&I, EG, wholesale and NGV customers are shown for illustrative purposes.						
Noncore customers typically purchase their own gas supplies.						

ATTACHMENT 4, TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ANNUAL AVERAGE DELIVERED NATURAL GAS VOLUMES
MILLION CUBIC FEET PER DAY

	Year	Delivered Volumes
Residential	2000	694
	2001	724
	2002	707
	2003	666
	2004	699
Core Commercial/Industrial	2000	263
	2001	274
	2002	277
	2003	273
	2004	295
Noncore Commercial/Industrial	2000	496
	2001	428
	2002	472
	2003	451
	2004	450
Electric Generation	2000	1,199
	2001	1,257
	2002	870
	2003	789
	2004	782
Wholesale	2000	446
	2001	475
	2002	425
	2003	377
	2004	427
TOTAL	2000	3,098
	2001	3,159
	2002	2,751
	2003	2,556
	2004	2,652

NOTES:

1. Core Commercial & Industrial includes Gas Engines, Gas Air-conditioning and NGV load. Residential includes master metered & CARE
2. Electric Generation excludes electric generation and cogeneration load of SDG&E and Southw est Gas
3. Wholesale load includes DGN. Wholesales load in April 2005 includes SDG&E's large billing adjustments for the prior years.
4. SoCalGas data for 2005 available only through November 2005.

ATTACHMENT 4, TABLE 3

SDG&E AVERAGE ANNUAL NATURAL GAS RATES

CENTS PER THERM

	2000	2001	2002	2003	2004	2005
Residential						
Transportation Rate	44.47	40.72	44.24	47.36	42.93	50.94
Procurement Rate	47.07	83.65	30.40	48.98	58.64	78.38
PPP Surcharge	-	1.86	5.41	5.95	4.70	4.35
Total Rate	91.54	126.23	80.05	102.28	106.27	133.67
Core C&I						
Transportation Rate	39.01	32.75	31.54	31.59	26.99	29.41
Procurement Rate	47.07	83.65	30.40	48.98	55.32	78.38
PPP Surcharge	-	0.88	3.46	3.02	2.59	3.44
Total Rate	86.08	117.28	65.40	83.58	84.89	111.24
NonCore C&I						
Transportation Rate	9.69	8.80	7.45	8.51	8.32	9.77
Procurement Rate	47.07	83.65	30.40	48.98	55.32	78.38
PPP Surcharge	-	0.55	2.78	2.00	1.85	1.83
Total Rate	56.76	92.99	40.63	59.48	65.50	89.98
Semprawide EG						
Transportation Rate	4.62	2.75	2.19	3.03	3.48	4.02
Procurement Rate	47.07	83.65	30.40	48.98	55.32	78.38
PPP Surcharge						
Total Rate	51.69	86.40	32.59	52.01	58.80	82.40
NGV						
Transportation Rate	10.18	7.22	7.37	7.78	7.00	8.06
Procurement Rate	47.07	83.65	30.40	48.98	55.32	78.38
PPP Surcharge	-		3.43	0.90	1.82	1.92
Total Rate	57.24	90.86	41.20	57.65	64.13	88.36

Note: The SDG&E procurement rates for noncore C&I customers, EG customers, and NGV customers are shown for illustrative purposes. Most noncore customers procure their own natural gas supplies.

ATTACHMENT 4, TABLE 4

SAN DIEGO GAS & ELECTRIC COMPANY
ANNUAL DELIVERIES BY CUSTOMER CLASS
MILLION CUBIC FEET PER DAY

	Residential	Commercial	NGV	Industrial	Cogen	Electric Generation	Annual Total
2000	91.2	38.7	1.0	21.2	45.8	181.1	379.0
2001	92.4	44.4	1.3	12.0	43.5	231.1	424.7
2002	91.2	46.6	1.8	9.7	55.2	176.8	381.4
2003	85.9	44.5	2.1	10.2	54.1	116.6	313.4
2004	91.1	45.8	2.2	9.7	56.9	144.3	350.0
2005	85.2	45.3	2.4	10.2	51.0	111.8	305.9

ATTACHMENT 4, TABLE 5						
PACIFIC GAS AND ELECTRIC COMPANY						
AVERAGE ANNUAL NATURAL GAS RATES						
cents per therm						
	2000	2001	2002	2003	2004	2005
TOTAL CORE END-USE RATES						
Residential Non-CARE	81.98	101.27	68.39	95.26	94.59	126.89
Small Commercial	79.35	100.73	71.14	95.28	94.23	122.17
Large Commercial	59.16	80.53	53.53	76.95	75.32	96.80
TOTAL NONCORE END-USE RATES						
Industrial Transmission	2.57	2.21	2.79	4.36	4.84	2.14
Industrial Distribution	11.31	9.76	10.56	12.04	11.67	9.41
EG	1.96	1.66	1.73	2.36	2.07	1.76
Wholesale:						
Coalinga	2.23	1.89	2.01	2.56	2.94	2.38
Palo Alto	1.85	1.56	1.69	2.25	2.16	1.73
West Coast Mather - T	3.22	2.73	2.30	2.86	3.66	2.46
Island Energy	4.68	3.99	4.46	5.02	8.34	4.36
Alpine	1.48	1.85	2.04	2.59	3.01	2.45
West Coast Castle	0.10	1.03	0.75	0.75	1.85	4.32

ATTACHMENT 4, TABLE 6

PACIFIC GAS AND ELECTRIC COMPANY
AVERAGE ANNUAL NATURAL GAS DELIVERED VOLUMES

AVERAGE MONTHLY DELIVERIES (therms)						
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
CORE						
Residential	179,509,281	167,844,410	171,716,549	168,774,583	171,276,141	164,682,456
Small Commercial	89,848,347	63,958,845	63,963,787	62,995,599	63,654,243	62,965,204
Large Commercial	2,081,306	5,689,310	7,415,183	7,073,417	6,418,330	6,894,676
NONCORE						
Industrial Transmission	131,955,006	106,257,790	104,232,720	108,123,340	106,327,250	111,086,320
Industrial Distribution	30,311,170	23,809,560	21,374,110	21,871,970	21,133,760	21,594,470
EG	279,471,010	331,794,750	249,561,630	224,485,910	220,469,490	217,078,330
Wholesale:	3,415,250	3,268,230	3,157,180	3,088,580	3,104,700	3,104,940

AVERAGE DAILY DELIVERIES (million cubic feet per day)						
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
CORE						
Residential	579	541	553	544	552	531
Small Commercial	290	206	206	203	205	203
Large Commercial	7	18	24	23	21	22
Core Total	875	765	784	770	778	756
NONCORE						
Industrial Transmission	425	342	336	349	343	358
Industrial Distribution	98	77	69	70	68	70
EG	901	1,069	804	724	711	700
Wholesale:	11	11	10	10	10	10
Noncore Total	1,435	1,499	1,219	1,153	1,131	1,137